Renewable and Sustainable Energy Reviews 15 (2011) 5003–5012

Contents lists available at SciVerse ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Market evaluation of hybrid wind-storage power systems in case of balancing responsibilities

Rodica Loisel[a,*], Arnaud Mercier[a], Christoph Gatzen[b], Nick Elms[b]

[a] European Commission, DG Joint Research Centre, Institute for Energy, P.O. Box 2, 1755 ZG Petten, The Netherlands
[b] Frontier Economics Limited, 71 High Holborn, London WC1 V 6DA, United Kingdom

ARTICLE INFO

Article history:
Received 27 December 2010
Accepted 5 July 2011
Available online 29 September 2011

Keywords:
Wind
Power storage
Intermittency
Market evaluation

ABSTRACT

This study investigates the economics of a wind power farm with a long-term market perspective, considering high shares of wind energy, constraints set on the energy variability, and the removal of support schemes such as feed-in tariffs. The contractual agreement with a compressed air energy storage facility (CAES) would create a hybrid wind-storage system that would allow a wind power operator to reduce the intermittency of its output and to provide flexibility to the system. The study gives a market value to the wind power at a project level of several gigawatts capacity located in France, by using a technical and economic optimization model. Results indicate the cost of balancing the intermittency for the wind operator and show that under baseline conditions, the hybrid wind-storage system would have negative profits despite price arbitrage operations and ancillary services provided to the system. Alternative tests show that the economics can improve when the influence of the wind power on the spot price is accounted for. The study is focused on the long term market situation in France, which is characterized by increased balancing needs, an ageing infrastructure, uncertainties in carbon and gas prices, and increased power imports.

© 2011 Elsevier Ltd. All rights reserved.

Contents

* Corresponding author. Tel.: +31 647235 959.
E-mail address: Rodica.Sandu@ec.europa.eu (R. Loisel).

1364-0321/$ – see front matter © 2011 Elsevier Ltd. All rights reserved.
doi:10.1016/j.rser.2011.07.054

1. Introduction

The objective of this study is to analyze the economics of wind power within a long-term market situation, where wind power generation attains a large share of the demand. The wind power technology is considered mature enough for removing feed-in tariffs and sale obligations. This market formulation aims at evaluating the wind power within the strategy to reduce output fluctuations, to perform price arbitrage and to provide system services.[1]

The deployment of renewable energy sources (RES) in the European Union has led to substantial wind power generation, but has also increased the concern over the control of intermittent resources fed into the system. Therefore, large-scale penetration of wind power in the mid-long term will require moving towards a more integrated and flexible European electricity system [2]. It is estimated that increasing the share of wind energy, e.g. more than 20% of the load, would result in higher system costs than for including conventional generators. These costs are attributed to additional balancing reserves needed to ensure system reliability and to avoid network congestion [3]. The share of the balancing reserve would depend on each operating system, but could attain more than 20% of installed capacity in some systems [4,5].

Among techniques envisaged to accommodate large-scale generation from renewables, electricity storage is of significant interest for system operators and RES developers. In addition to balancing services, storage could provide a wide range of services, such as price arbitrage, grid congestion absorption, reactive power provision and electric supply capacity [6,7]. However, its competitiveness with other forms of flexibility – for example gas turbines – is rather weak under current market conditions, because generally the benefits that can be provided by a storage facility are valued at a lower price than its investment and operation cost [8]. Storage has to perform several functions to be cost effective [9,10].

In this study, a hybrid power plant composed of wind farm and a compressed-air storage facility is considered. The storage facility supports the balancing needs of a wind farm and can optimally be charged with wind-based electricity and grid-supplied power. The contractual arrangement is hybrid system-specific, as the two technologies are not in competition and benefits are aggregated between them. Technically, the wind power fluctuations are levelized through storage to ensure load-following. The wind farm is capable of meeting the grid and demand specifications without depending on back-up capacities. Economically, in line with the hybrid concept, power can be transmitted to the grid by either the wind or the storage component of the hybrid plant. Internally to the hybrid plant, the storage facility receives an infeed of wind power at zero cost. This infeed from wind typically occurs when sales to the TSO are less profitable or during low demand periods, as the inflows and outflows of power are determined according to a set of cost-efficiency criteria.

As this hybrid system is not available yet, this study investigates the way to use and design the wind-storage-transmission system within the strategy to control the wind power intermittency (Fig. 1). Given the storage support, the wind farm can react through storage to market prices. The interesting point of the study becomes the evaluation of the wind power on different power market segments, such as the wholesale market and the balancing mechanism. This paper gives an overview of the existing market options and of the market size that such a system can realistically respond to.

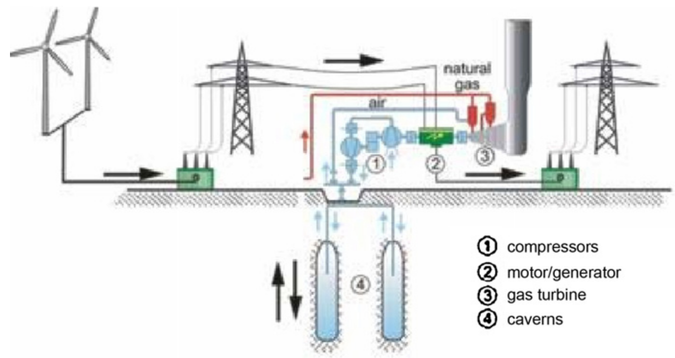

Fig. 1. Configuration of the wind-storage-transmission system.

A scenario for large-scale wind penetration is built at a system level based on a local project consisting of 2 GW of on-shore wind. The wind intermittent profile is based on real generation figures, and mathematical hourly model is applied to maximize the wind-storage system profits during one year. The case study is performed based on the French power market, where several elements could limit the implementation of additional back-up capacities, including: the high share of nuclear generation (75–80%), a relative over-capacity situation, and base-load inflexibility. Currently, French balancing needs are met through hydro and fossil-fuel power plants, but in the longer term, higher wind power generation will create additional demands on system flexibility [11].

A brief description of the operating electricity markets and their flexibility needs are presented in Section 2. The wind-storage system and the assessment framework are presented in Section 3. Simulations of the proposed scenarios with respect to the power pricing evolution and future market organization are analyzed in Section 4. The main results of the study are provided in Section 5.

2. Flexibility operations in a competitive electricity market

This section introduces basic notions and mechanisms to understand how the power market segments interact, and highlights the balancing market and the needs for reliability in the presence of wind power fluctuations.

Flexibility needs occur since unused electricity cannot be easily stored to balance between supply and demand. Consequently a balancing between supply and demand is necessary at all times within a control area. This requires the procurement and the settlement of complex services to adjust the system, by contracting power on several market segments. One key factor for defining these transactions is the time frame for delivery. Typically, the power trade taking place before delivery is performed on the forward market. In the short run, forward energy can be traded in the day-ahead or spot market 24 h before delivery, in intraday markets functioning within the day, or in real-time in the balancing market functioning within the hour [3].

The main function of the balancing market is to counteract imbalances by the day-ahead transactions. The demand side of this market is made up of transmission system operators (TSO), and on the supply side the participants include electricity producers and consumers. To prevent blackouts, fast generation capacities have to be ready to operate as reserves before real-time. They can be procured through the balancing market. The need of flexibility is not the same as need of reserves, since a part of the net load variation can be forecasted. Most of the flexibility needs are met by the on-line generators. To prevent disruptive events, reserves are called upon to restore the balance of the power system. These

[1] System services are all services provided by a system operator to all users connected to the system. Some users provide some system services that are ancillary to their production or consumption of energy. These system services are called ancillary services. Eurelectric [1] gives a detailed definition of ancillary services. The current study makes reference to ancillary services, more precisely to frequency control and standing reserves.

reserves are categorized normally by the time scale required for intervention.[2]

From a contractual point of view most of the flexibility is provided on the day-ahead and real-time markets using the capability of the on-line generators to adjust their energy deliveries. And when on-line generators are not sufficient, additional support can be used through the reserve market for procuring ancillary services and contractual reserves. All these elements are part of the balancing mechanism. These transactions cover the real-time market, by payments for the delivery of balancing services, and the reserve market, by additional capacity availability payments on a longer-term basis through bilateral contracts, compulsory provision, tendering or spot market. The market for ancillary services has been more clearly identified since the recent liberalization of the power market in Europe and the separation between network and generation activities. This market is however tightly linked with the energy market, since a generator can make the choice to allocate its supply as an ancillary service or as energy. This depends on its technical criteria but also on the rules of electricity markets.

The evolving structure of the power market requires that the market for ancillary services adapt to new factors such as environmental pressure, higher energy prices, ageing infrastructure, higher competition and new technologies [12]. New renewable-based generators, like wind power turbines, add new service requirements given the variable nature of the resource.

An indicator of the contribution to the system reliability is the capacity credit. It is usually expressed as a share of the installed capacity of the generators installed. It is system dependent and for wind generation ranges between 10% and 35%. Given the resource intermittency, the capacity credit declines as the share of wind-based electricity supplied increases. The amount by which the system must raise its generation capacity is referred to as stand-by capacity or back-up capacity or system reserves [4]. The impact of the intermittency on the system depends on many factors including:

- the quality of wind resource and the aggregation of wind plant output,
- the robustness of the grid and the balancing areas,
- the market structure and the gate closure time (the end of the day-ahead market and the beginning of the real-time market).

For instance, the smaller the capacity credit, the higher the back-up capacity needed to maintain the system reliability. Power systems face different balancing needs, depending on the degree of flexibility in their generation structure.

In Germany, where fossil-fuel power plants are predominant, the existing power stations would be large enough to provide the extra balancing power capacities for 36 GW of wind power (20% in the power generation) that are likely to be installed in 2015 [13]. This will incur however an opportunity cost as the extra costs for withholding those balancing plants from covering the demand on the wholesale market.

By contrast, in United Kingdom, which is not connected to UCTE (the Union for the Coordination of Transmission of Electricity), the additional conventional capacity required during demand peaks would amount to 15–22% of installed intermittent capacity [4,5]. While in France, wind capacities higher than 8–10 GW (9% of the power generation) would require an additional 500 MW of reserve capacities or further grid extensions [14].

In conclusion, the provision of stand-by capacities is the main factor to manage the effect of variable generation from wind power. This is particularly necessary in systems with low flexibility (i.e. low ramp rates and high start-up times of capacities) or in systems with some flexible but ageing power plants. In the case of large-scale penetration of wind power, additional requirements could be imposed on wind power generators to offset variable generation with supply flexibility to the system, necessary to stabilize voltage and frequency [15].

In France, the provision of energy and ancillary services is not mandatory, neither for wind power plants nor for other generators. In the future, this arrangement could change with the current contraction of the current over-capacity and the increase in wind power penetration. These aspects are further detailed in the following sections.

3. Case study framework

3.1. Market description

France has the second largest wind potential in Europe. Despite the large share of nuclear power in the electricity production (78%), there is a strong emerging wind energy market: the installed wind capacity increased from 757 MW in 2005 to 3500 MW in 2008. The share of renewables in electricity generation was about 14% in 2009 and may increase to more than 23% of the French electricity demand by 2020 [16].

Electricity generation is largely dominated by one company, EDF, which owns around 85% of the total generators. In the year 2000, a wholesale market was launched which handled financial transactions via the *Powernext* platform (essentially day-ahead market) and also bilateral contracts, *OTC* (over the counter). The wholesale market is developing fast and represents more than 40% of the flows on the French market. Despite developing organized markets, OTC negotiations dominate the market with 93% of contracts on the forward market and 30% on the spot market [17]. Typically, power volumes negotiated via OTC contracts are not known, and the only public information is the volume physically delivered. The balance between flows of injections and withdrawals is ensured through the adjustment mechanism that aims at setting competition between participants for ensuring reliability and security of supply. The French TSO, RTE (Réseau de Transport d'Electricité) obtains through this adjustment mechanism balancing services via spot transactions for short or long positions in real-time, and buys also ancillary services via bilateral contracts. In this paper, the market segments that are evaluated are: (1) the wholesale spot market, (2) the balancing mechanism related to the day-ahead and intra-hour adjustment, and (3) the balancing services related to the reserve market: the secondary and the tertiary reserves.

The regulation of intermittent renewable energy is ongoing and has as starting point the experience gained in islands, such as Corsica, Guadeloupe, Guiana, Martinique, Mayotte and Reunion Island. For instance, the Ministry of Environment launched in 2009 a call for tender for photovoltaic (PV) energy systems under the constraint for generators to control the intermittency of their power flows in the above regions [18]. To that the endowment of PV generators with storage systems is mandatory. The sizing of storage should attain at least 1/3 of the PV capacity to can ensure a variation of the PV generation lower than 15% of the nominal power of the PV plant for half-hour time steps. The PV-storage system should be

[2] Primary reserves are used to manage short-term load fluctuations, with a response time within 30 s. Secondary reserves are used to restore the scheduled load-flows between control areas and to cope with outages in generation or transmission. Activation starts immediately after a disturbance and secondary reserves must reach their full level of provision within 5 min. Tertiary reserves are used to restore and support secondary reserves. Tertiary reserves should be fully available 15 min after activation. Due to the response time, primary and secondary reserves need to be running (or spinning), whereas tertiary reserves do not.

also able to provide primary reserves as high as 10% of the power generated. Such constraints aim to stabilize the frequency of the system. A similar context is designed in the current study assuming large-scale of intermittent energy in the metropolitan France where constraints could be set on the generators to limit the power fluctuations and ensure the frequency management.

3.2. Hybrid system description

The study assumes that the on-shore wind farm is located near a storage site, suitable for the implementation of a compressed air energy storage facility (CAES). However, this joint location is not a necessity if sufficient grid capacity is in place between the storage facility and the wind farm. Geological details for salt structures and cavern fields in France can be found in Gillhaus [19], and projects for wind farms development are documented by RTE [11]. For the study purpose, a large wind farm was selected to be connected to a CAES application and to one or several injection points of the TSO. The study time frame is 2030, which is set considering the current installed capacity, the wind penetration rate speed, and national and regional targets for RES integration. From a technical point of view, the year modeled assumes both technologies are in a mature development stage.

For wind turbines, the investment costs amount to 955 €/kW and operation and maintenance costs to 24 €/kW. The wind farm capacity is 2 GW, and the yearly capacity factor is 2300 equivalent full load hours (or 26%). The technical life time is 20 years.

The storage technology chosen is sized to match the wind farm needs for back-up capacity and to provide ancillary services to the system. A detailed description of CAES technologies and further references can be found in [20]. The CAES project considers capacities for production of 1200 MW and for compression of 1440 MW, with an energy storage capacity of 10 h. The study assumes that 1.21 kWh of electricity is produced and 4644 kJ of natural gas consumed for each kWh of electricity stored, giving a round trip efficiency in terms of electricity of 121%. The investment cost assumed is 625 €/kW in 2010, to which a reduction of 15% is applied, due to assumed progress from R&D programs and increased experience which results in learning effects. The technical life is 30 years.

The economic lifetime of the wind-storage project is assumed to be 20 years.

The transmission line connects the project to the rest of the system. The total transmission capacity of the hybrid system is set to 2000 MW under the assumption that no bottleneck occurs. The way the hybrid power plant is modeled and the data required to valuate it are described in Section 3.3.

3.3. Model framework

The wind-storage project is modeled so that the storage facility ensures firm capacity to the wind farm. The storage charging is modeled to optimally select between wind-based electricity and grid-supplied power. The operation of the wind-storage system is simulated by using a computation model, which dynamically optimizes the hourly operation over a year, given its technical constraints. Details of an earlier version of the model can be found in Gatzen [6]. The model is deterministic and aims to maximize the annual profit of the hybrid wind-storage system, under the assumption that the two technologies are not in competition and benefits are aggregated between them.

The profit is computed as revenues less operating costs, given exogenous hourly wholesale and balancing power prices, hourly wind infeed profiles and the ability to select which power services are provided in an hour.

The system can choose either to store the electricity or to provide it to the TSO under the constraint of load-following provision. Hourly fixed demand is represented by the load curve of the French demand, being modeled as a fraction set at 0.9% of the domestic demand in order to obtain an annual supply (4.5 TWh) roughly equal to the annual wind inflow (4.6 TWh). The *local* demand is a synthetic curve built for this exercise in order to simulate the load fluctuations as reflected by the aggregated national load curve. In this way, the model can deal with both hourly load and wind power fluctuations.

The annual wind output is split optimally on an hourly basis between the provision of the fixed hourly demand and the possibility to store the electricity. The last option depends on the wind inflow, the demand magnitude and the capacity to store the power at that moment. By levelizing the wind output through storage, the load-following avoids wind power fluctuations, so that the system supplies power continuously, and the TSO avoids providing additional back-up capacities during low wind infeed periods.

The hourly demand is calibrated against the total French demand and includes a fixed demand for base-load demand and for balancing intermittency to represent the behavior of the system as a whole. In addition to meeting the demand load, the hybrid system can act freely to supply the wholesale market through price arbitrage and on the reserve market. The probability of calling the wind-storage system is fixed over the year along with the capacity reserved for this market.

The degree of freedom to act on these markets after meeting the fixed demand is set by the call probability for ancillary services, and the volume of energy stored. The electricity stored in the CAES facility originates from the wind power generation and the withdrawals from the grid during off-peak periods. When the wind inflow exceeds the demand, the excess is stored in the CAES facility. Even during peak periods, this excess is stored too, and power can still be delivered to the TSO through the CAES turbine, since the charge and discharge cycles are assumed to be decoupled over time.

Investments in wind and storage are not a decision variable in the model, as capacities were specified exogenously. Profits, as revenues less operating costs, are aggregated between the wind and the storage operators. Revenues result from hourly wholesale price arbitrage and production of electricity for secondary and tertiary reserves. Costs are considered in terms of their variable and fixed components (see Appendix A). Variable costs account for start-up costs, fuel consumption (gas in the case of CAES), and for the variable costs of filling the storage, storing the electricity and delivering the electricity to the grid. Fixed costs account for the fixed annual operating and maintenance costs, and for the investment costs. These costs are annuitized, taking account of economic lifetimes, the construction times, and the capital finance and discount rate (10%).

The economics of the project is assessed by calculating the net present value (NPV), which gives a uniform value (€/MWh) over the economic lifetime of the system. The analysis considers that the project operates identically during all lifetime years with respect to the generation and market choices. The NPV provides a composite value defined by cash inflows and outflows, investment costs, and the system's discounted net generated electricity:

$$NPV = \frac{\sum_{t=1}^{T}[(REV_t - CST_t - OPEX_t)/(1+r)^t] - INV_0}{\sum_{t=1}^{T}[EG_t/(1+r)^t]}$$

where t is the year, T the economic life in years, REV the annual revenue from the sale of electricity and ancillary services, CST is the annual cost of electricity withdraw from the grid and stored, $OPEX$ is the annual operating expenditure, INV_0 is the total investment

cost, *EG* is the annual electricity sold on the market, and *r* is the discount rate.[3]

3.4. Data description

Market conditions represent the French power market, including the wholesale market, the adjustment mechanism for balancing short and long-positions, and ancillary services. The databases for the hourly demand cover the year 2009 and are issued from ENTSOE publications.[4] The annual demand assumed for the project amounts to 4.5 TWh, with a peak load of 850 MW. From the supply side, the wind profile is derived from real data on wind power generation from the German market in the control area where the German utility E.ON operates in 2007.[5] The wholesale market is described through the spot price for 1 h time step, with data from 2009 published on the Epexspot site.[6]

The French balancing systems undertaken on the wholesale market includes both upward and downward regulations [17]. The wind-storage plant is used in this analysis to regulate the upward demand only, since the downward position corresponds to a virtual (contractual) excess supply of one generator. That generator might find efficient to generate the whole contracted power volume and to avoid shut-down costs and eventual penalties, while contracting directly with the wind-storage operator. This arrangement would add additional assumptions to this hypothetical project. Therefore the balancing mechanism is limited to upward regulation, where the payment takes place at the day-ahead price. Other services could be provided on this market, like regulation for congestion avoiding. This market is still limited as volume, and benefits would be difficult to evaluate, given the lack of data.

As for the balancing mechanism taking place on the reserve market, this makes the computation frame more complex, given the lack of transparency of payment conditions and the difficulty to estimate the future needs for ancillary services. System services in France are contracted through bilateral contracts, usually for 3 years, with payments for capacity availability (€/MW) and for positive (+€/MWh) or negative regulation (−€/MWh). The storage facility is assumed to provide four ancillary services for upward and downward regulation for each secondary and tertiary reserves [10].

Capacity payments are made by the TSO, regardless of whether the plant is called to increase or decrease energy output. Hourly capacity prices are set as a function of on-peak and off-peak periods respectively: 6 €/MW and 12 €/MW/h for upward secondary reserve; 6 €/MW and 3 €/MW/h for downward secondary reserve; 4 €/MW and 8 €/MW/h for upward tertiary reserve; and 5 €/MW and 3 €/MW/h for downward tertiary reserve. For a comparative purpose see data for Denmark in Ekman and Jensen [21] and for Germany in BNetzA monitoring reports [22] (Table 1).

If the reserves held by the storage plant are called, energy payments are also made by the TSO's to the hybrid station. Prices apply as margins to the wholesale price. These services are more costly than wholesale power: since prices and volumes are often fixed for a long time, this usually entails higher transaction costs to prevent against changes of market conditions. The margin set in this model for the secondary reserve is 25% for off-peak periods and 50% for peak periods; while for tertiary reserve is 10% for off-peak periods and 30% for peak periods. These margins apply to both upward and downward reserves. Tariffs account also for the difference between night and day pricing.

Table 1
Hourly capacity payments for secondary and tertiary reserves (€/MWh).

Reserve		Off-peak	On-peak
Secondary	Positive	6	12
	Negative	6	3
Tertiary	Positive	4	8
	Negative	5	3

The probability of calling the wind-storage system for providing reserves is set at 15% for the secondary reserves and at 2% for the tertiary reserve. These numbers were calibrated against the total national reserve, so that the wind-storage system supplies realistic power volumes. Power storage is assumed to offer 5% of the turbine capacity for upward reserve and 5% of the injection capacity for downward reserve, for both secondary and tertiary reserves. In absolute terms, this means that up to 60 MW of the CAES capacity may be used to provide upward reserve and up to 70 MW downward reserves.

3.5. Scenarios definition

Three scenarios are built around assumptions set on potential wind power development and market rules. The reference case presents the economics of the wind-storage project valuated at the current market price. Two alternative scenarios were also tested for different evolutions of the price and the price spread between on- and off-peak periods. Both wind and storage technologies are affected by the price evolution and its spread; on the other hand, they both can reduce the price if their infeed is large enough to influence the market [23,24].

The reference case (REF) assumes a system with large scale wind penetration in France with major changes in the current regulation in terms of flexibility requirements. Currently, French law provides no obligation for generators to participate in frequency and voltage control. Still some technical conditions are put on the new generators on their ability to participate in ancillary services provision [25]. For the primary control, they have to be able to participate if their capacity exceeds 40 MW and their contribution should be superior to 2.5% of their capacity. For the secondary reserve, the threshold is set to 120 MW and the contribution to 4.5%. This regulation does not apply to intermittent energy sources; therefore wind power generators are excluded from primary, secondary and tertiary control.

In the long term, the wind technology is expected to be mature enough to compete with conventional generators. Therefore, for large wind infeed quantities, the wind power plants will likely provide reserves to compensate for supply fluctuations as required for PV generators in the French islands [18]. Simultaneously, the wind power could be placed in a market context and be subject to variations of the market price. Currently, renewable investments in France are largely driven by support schemes such as feed-in tariffs. In this scenario the efficiency of the investment in real market conditions is tested. Therefore the feed-in tariff is removed so that the project can be evaluated within a scheme based on wholesale power prices.

Under flexibility requirements constraints, a wind project of several GWs would be required to have back-up capacities. Since wind and conventional generation are rarely closely connected to each other in the grid, the option of investing in storage facility appears convenient. Other aspects could add to the necessity to compensate for the intermittent nature of the wind power such as:

[3] When the NPV indicator of a project equals zero, the stream of income enables the investor to exactly recover the project's investment costs during the economic lifetime of the project, taking into account the financing cost of the investment. A negative value for the NPV indicator shows the additional value required for each unit of generated electricity in order for the investor to exactly recover the project's investment and financing costs. A positive value for the NPV indicates that the project nets an economic profit over its economic lifetime.

[4] www.entsoe.eu (website last accessed on 20/09/2010).

[5] www.bdew.de (website last accessed on 05/09/2009).

[6] www.epexspot.com (website last accessed on 20/09/2010).

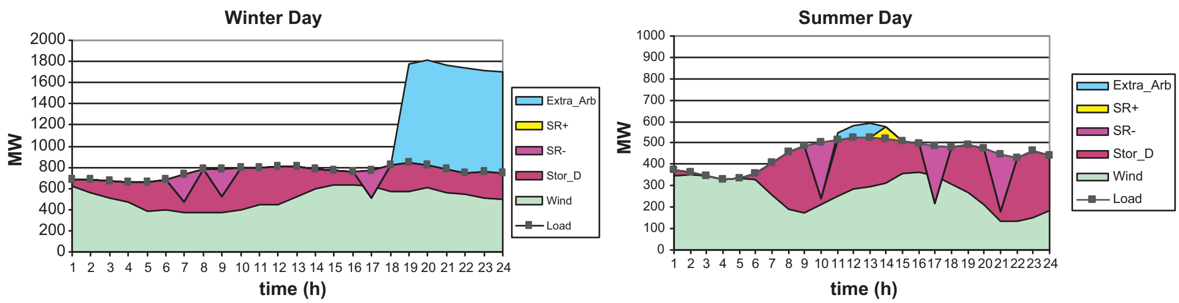

Fig. 2. Market segments supplied during two winter and summer days, MWh. *Note*: SR− is the power subtracted from the grid as negative reserves, SR+ is the positive reserve, Extra_Arb is supplied above the fixed load, Stor_D is the power supplied by the CAES to meet the fixed demand, along with the Wind power supply.

the forecasts error, the location of wind farms in areas with usually low local power demand and low population density; and the probability that the growth of the wind farm capacity would exceed the growth of the transmission capacity, with consequent bottlenecks and wind curtailment events.

The first alternative scenario, named Wind Influence on the Price (WIP), estimates the economics of the wind-storage system taking account of the influence that the large wind power infeed could have on the spot price. Experience and analytical demonstrations show that large shares of wind power influence the electricity price. EWEA [26] performs a state-of-art and reports an effect range between 3 and 23 €/MWh in the merit order curve. Qualitatively, high wind power generation would lower the spot power price; while during low wind power generation, the spot price would tend to increase since reserves are not necessarily ready in anticipation of wind inflow drops [27].

The absolute effect of wind power on the spot price is uncertain. As an alternative to the benchmark, the spot price is increased by 20% during periods with low wind inflow and a decrease in price by 20% during high wind generation hours. Additional motivation to run this test is the use of different data basis, e.g. the French wholesale price and the German wind profile. Then the spot price vector is not correlated to the wind power curve and does not account for the consequently influences.

The scenario raises questions around the issue of supplying cheap energy with high investment cost. This relates to the social value of wind power generation that would require that consumers to pay less for their consumption but would have them paying higher investment costs and higher energy prices when the wind does not blow.

The second alternative scenario, named the Cost-Efficiency case (EFF), calibrates the NPV indicator of the wind-storage project and reports values and conditions under which the system becomes cost effective. The way the demand is modeled, by calibration on the domestic load, limits market opportunities for the wind-storage operator to supply more power during on-peak times. This reflects a constraint put on the resource allocation timing with only limited possibilities to choose for the moment when the stored power is delivered. Given the project specificities to deliver power during critical points of load, the importance of the peak prices is calibrated to justify the project from economic point of view. However, from a technical and social point of view, the scenario launches the debate around the value of power quality and delivery security in the French market; and on ways the power system can socialize the value of energy independency and climate change prevention.

The national power regulating commission, CRE, noticed a correlation between the French power price and the gas price, even if the domestic marginal generation is mostly based on coal and rarely on gas [17]. The CRE explains the correlation through increased import flows during on-peak periods from interconnected countries such as Germany (based largely on fossil-fuel generation), even when the power price is lower on the French market. One of the explanations is the lack of liquidity of the French power market. On the other hand, in a fully integrated market, this price increase would be simply the result of different trade-off opportunities where the equilibrium price is triggered up by demand-supply system at a regional level. However, the consequence is the increase in the French price spread under the influence of prices of oil, gas and CO_2. The decrease in reserve capacities on the French market in the long term could add to this spread, along with the concerns over the energy independency and security of supply.

4. Results and discussion

4.1. Wind-storage in the reference case

The reference case includes results of the total profit and its main components related to the wind-storage operation over the year. The wind and storage operations are performed posteriori to the investment decision. The decision variable is the annual profit on the wholesale market and the balancing market. The variable aggregates the hourly profits within an intertemporal framework with perfect foresights on prices and load variations.

Incomes are mostly taken on the wholesale market where the volume supplied is more important than on the reserve market (80% on an annual basis). A higher demand for ancillary services would increase the benefits since revenues include capacity payments and energy deliveries at a higher price than the spot value. However, at a local level the demand for reserves is limited. The capacity of 120 MW reserved for this market is sized to the national overall demand. In France, 660 MW of secondary control reserve and 1000 MW of tertiary reserve are held, being distributed among potential generation units located all over the country. Therefore, it is unlikely that all reserve capacities are assigned to only one unit.

The annual demand is calibrated against the annual wind inflow. A higher demand is technically feasible but it implies withdrawals from the grid to compensate for the difference between load and wind inflow, which would transfer the fluctuations to the rest of the system. Lower demands tend to favour the storage profitability as less constraint is put on the wind power supplied directly to the grid; then more storage opportunities would appear at zero costs, with a higher degree of freedom to act on the market segments.

The trade-off between different markets depends on the load and hourly prices (demand-side), and on the wind inflow, the storage capacity and the volume stored at the hour before the delivery (supply-side). A time-series representation of the generation by market segments over the course of one day is shown in Fig. 2.

Market conditions are defined with respect to value drivers such as the evolution of the spread of wholesale electricity prices between peak and off-peak periods, the share of the storage capacity sold on the reserve market, and the payments for the capacity

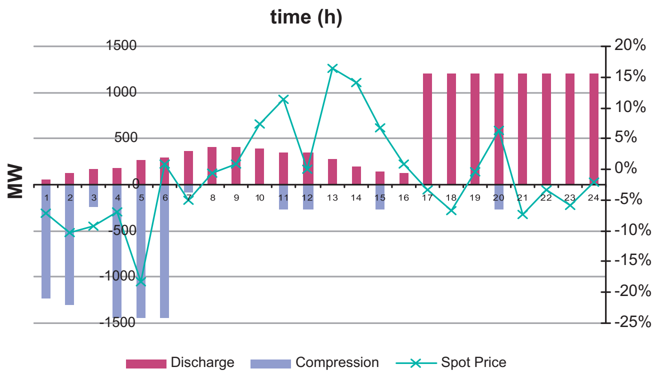

Fig. 3. The operation of CAES during a 24 h period.

availability for reserve provision. Technically, the CAES facility does not saturate the storage capacity as the intertemporal computation gives visibility to the future market opportunities and demand needs. The optimization of wind power between the delivery to the TSO and the storage option favours the first one under the demand constraint, shifting to the second one only once the first demand is met. Wind power storage occurs only in situations with the wind in excess of the load, as it accounts for the additional costs associated with fuel (gas) needed for compression and from the power losses from charging the inflow.

Fig. 3 shows a continuous variable discharge flow, even during base-load periods due to insufficient wind power, and a higher rate of discharge power during peak times, triggered up by higher spot prices. The storage operator would act differently without this demand constraint, and would prefer to concentrate the outflow during on-peak times. The constraint adds a cost to the project, which is the balancing price due to fluctuations. It reflects both the intermittency of the resource and the limited volume of the wind power supplied. However, social and system benefits can justify the political support for the wind integration that the industry experienced.

Table 2 summarizes some of the simulation results and shows the incomes and the optimal split of power supply between the different market segments. Within the benchmark configuration, the project records a negative profit value, as shown by the NPV indicator (−24 €/MWh). Decomposition by elements indicates the high share of investment cost in the total income: 65% for wind power plant, 25% for storage, and 40% for variable costs. The storage facility is closer to the market (NPV = −1 €/MWh), since the lifetime is 30 years and that the wind power stored is in fed at zero cost. If the storage operator should pay for this supply, it would face high costs, as a high share of the power stored is wind-based. See a discussion on market choices of CAES application as a single entity in Loisel et al. [8]. As for the wind power plant acting as a single entity, the NPV is negative given the high investment cost related to the limited volume supplied, i.e. 26% of the capacity. Within the same conditions, a capacity factor of 36% would be necessary to make the project attractive, which in exchange would add even more fluctuations in the system.

It is worth noting that the value of the wind power plant was higher before contracting storage – computed outside the model, as a single entity – than in this hybrid system (−17 €/MWh wind separately compared to −24 €/MWh for the hybrid plant). The difference could be seen as an indicator for the price of the quality of the supply, or the net cost of balancing the intermittency by means of a CAES, evaluated roughly as an annual average.

It was found that the cost of balancing is lower when the operator can make benefits from other market segments like price arbitrage and ancillary services provision. A storage capacity lower

Table 2
Simulations outputs for the reference case and alternative scenarios.

Scenario	Total power generation	Total revenues	Wholesale + spot balancing: Load-following		Wholesale + spot balancing: Extra[b]		Reserve markets, GWh: Reserves				Reserve markets: K	Reserve markets: (R+)[a]	Power generation: Wind	Power generation: Wind_stor	Power generation: Grid_stor	Power generation: Stor_discharge	NPV: Hybrid	NPV: Wind	NPV: CAES
							SR+	SR−	TR+	TR−									
	GWh	M€	GWh	M€	GWh	M€					M€	M€	GWh	GWh	GWh	GWh	€/MWh	€/MWh	€/MWh
REF	9471	385	7638	179	1792	120	39	104	1	40	29	29	3045	1484	−1509	3254	−24	−46	−1
WIP	9599	416	7687	179	1855	129	52	104	6	40	29	32	3042	1372	−1673	3336	−21	−44	2
EFF	12,726	638	9235	253	3416	305	72	91	3	25	25	37	3037	1505	−2825	4920	1	−33	23

Note: SR+, SR−, TR+ and TR− represent the secondary and tertiary reserves for positive and negative regulation; K represents the capacity payment, Wind is the direct wind infed into the grid, Wind_stor is the wind energy stored, Grid_stor is the power taken from grid to charge the storage, Stor_discharge is the total generation from CAES (which has been filled with wind power and the power taken from grid).

[a] It includes payments for positive reserve delivery only.

[b] Extra refers to arbitrage made outside the fixed load

than 1200 MW would be high enough to ensure the load following, e.g. 600 MW for the storage turbine. Higher storage is still preferred in order to increase profits from additional market opportunities. Other benefits, not included here, are implicit to this continuous power supply: benefits from avoiding error predictions that in some estimates amounts to 10% of the total wind generator incomes [28]; or benefits from avoided bottleneck and curtailment. These could be also significant as curtailment could amount in some systems to 10% of the wind power generation [29].

4.2. Alternative scenarios

Two simulations are performed and discussed around the spot price evolution (WIP scenario) and the price spread between the on-peak and off-peak prices (EFF scenario). Results are summarized in Table 2.

4.2.1. Wind power influence on the spot price (WIP)

This scenario makes a step forward related to the benchmark, where feed-in tariffs were removed and wind power operator was facing real market prices. In this test, the wind-storage operator faces a set of price volatility that the wind power itself generates on the spot market. The influence is reflected by large-scale wind penetration rates where the supply variation should be large enough to influence the market.

Prices are assumed to increase by 20% when wind power inflow is lower than 10% of its total capacity; and that prices decrease for wind inflow higher than 80% of the capacity. Between the two levels, the effect on the price is linear with the wind inflow trend. These figures have a testing purpose, since no relation is made between the wind supply and the remaining structure of the power generation on which the prices depend on. Theses assumptions are purely hypothetic; however, the mechanism is based on historical observations in Germany, Denmark and Belgium, and is analyzed in more details in EWEA [26].

Results for this scenario show improved values of NPV as compared to the reference case. As more power flows are traded and more opportunities appear for price arbitrage, both wind and storage facilities improve their economics. These findings are attributed to the storage that allows the operator to make arbitrage in function of the price volatility. Otherwise, the wind operator alone cannot choose the moment of delivery related to the price level and its NPV would be lower than in the reference case. Wind power has indeed no means to react to market signals and this is one of the reasons why wind power generators are not exposed to it when feed-in tariffs are applied. Market signals with cap-and-floor mechanism like in Spain can combine both schemes by partly exposing wind power to market prices while guaranteeing a minimum risk covering [23].

Decreasing the spot price during high wind inflow brings benefits to the system and consumers due to lower prices, but in the same time it decreases the income for the wind power generator. This acts negatively on its NPV, as the volume supplied remains unchanged. In the case of increased spot prices, the wind power generator could benefit from higher prices, at least at the beginning of its supply period.

To summarize, the positive effect of the wind power on the system harms the economics of the wind power, while negative effects tend to increase its value. In this scenario, the net effect is positive on the project tested; still the combination of wind and storage prevents the market from wind power fluctuations.

4.2.2. Price spread for a cost-effective project (Cost-Efficiency scenario, EFF)

This scenario tests the sensitivity of the project to the spot price, and calibrates the value that should be added to the initial price spread to make the project profitable. For this test, two load periods are defined, such as the base-load covering for each day of the year the period from 0:00 am to 10:00 am, from 3:00 pm to 7:00 pm, and from 10:00 pm to 12:00 pm. The remaining hours are here defined as higher price periods, covering the semi-base and on-peak periods, i.e. from 10:00 am to 3:00 pm, and from 7:00 pm to 10:00 pm. The average price is of 35 €/MWh for the base-load hours and of 55 €/MWh for semi-base and on-peak periods.

In this scenario, the additional value which should be added to the initial price spread to make the project cost-effective is in average of 40 €/MWh. This value appears relatively high compared to the current market indicators in France.[7] The additional spread value should be put in the perspective of future trends on the French market and more generally on the European power market. The following three points support an increasing trend of the price spread: (1) the fuel and carbon prices influence; (2) the internalization of costs for energy independency and security of supply; (3) and the market evolution with respect to the decentralization in generation, the reduction of over-capacity, the ageing infrastructure, and the uncertainty related to the organization of ancillary services markets. These points are expanded upon below.

(1) The price spread on the French market could be subject to significant influences from increasing carbon and fuel prices. The off-peak load in France is met by nuclear and hydro power plants, and the peak load mostly by coal-fired power plants. This implies that an increase in the carbon price would affect the on-peak generation only and would increase the price spread. This effect was estimated to around 4€ or 22% of the power price in 2005, a year when emission quotas were freely distributed [30]. The price effect is naturally lower in France than in neighbour countries, UK or Germany, due to the high proportion of non-carbon intensive technologies employed in the French generation (nuclear and hydro/storage hydro). For costly CO_2 allowances, the price margin could increase directly, as a domestic generation-effect, and indirectly, as an import-effect from neighbouring countries. An increase in oil and gas prices would affect the power price on the French market due to interconnected countries which are a source of fossil-fuel based imports in particular during on-peak times [17].

(2) The degree of influence on the power price from interconnected countries is related to the degree of energy dependency of the French system, defined in connection with the availability of capacities during on-peak times. With concern to the long term security of supply, rough estimates show that 25 TWh generated from around 10 GW wind capacity would increase the France level of energy independency by 1% [31]. The local project tested cannot give a value of the measure of the energy independency it can reduce. A more integrated assessment performed at a system level would be necessary. Wind connected to storage would naturally improve this indicator, by reducing the share of import flows or back-up capacities based on imported fuels. This type of benefits could partly justify the investment cost in combining the two technologies that could be particularly efficient during critical peak-load times.

The value of the security of supply is also difficult to estimate, since tariffs for ancillary provision and reserves are regulated or fixed through bilateral agreements. The lack of transparency on this market often sends negative signals to investors as no anticipation on the market behavior can be made, neither on

[7] Other studies have performed similar simulations for wind-CAES projects in USA. They show that CAES-wind is competitive with conventional back-up capacities for a carbon price of 35 USD/tC or 128 USD/tCO2 [33]. Anyway, to make results comparable among studies, a common definition of the peak and off-peak periods would first be necessary.

the peak price for short terms or on investment opportunities for the longer term [17]. This concern is more acute in a context where scarce interconnection capacities limit a fully integrated European power market to be achieved [32].

(3) Liberalization of the electricity markets raises challenges for the market organization and power prices evolution. If more centralized markets concentrate trades and increase market liquidity [3], the decentralization instead would decrease the ability to optimize the use of capacities. The ageing infrastructure in generation and transmission intensifies the debate on the future power infrastructure in France and the capability to meet the demand without significant price changes. Uncertainty on the future price spreads relies on these developments. A better conversion of technical costs into the market prices could follow from deregulation, which would result in higher power prices, and serve to encourage development of innovative solutions to improve the quality of the power supply.

5. Conclusions

This study has evaluated the economics of a wind power farm in France with a long-term market perspective, considering high shares of wind energy, and responsibilities to balance the intermittency assigned to wind generators. The study investigates the technical and economic conditions for the wind operator to meet its flexibility needs in combination with a compressed air energy storage facility. Main results are as follows:

- Under the current power pricing system, the wind operator would record a net present value of −17 €/MWh, which attests for the importance of guarantees and feed-in tariff schemes adopted in France.
- The hybrid wind-storage system shows negative profits too, −24 €/MWh, despite an optimization behavior that the local system adopts to supply different power market segments additional to balancing provision: price arbitrage and ancillary services.
- Alternative tests show improved economics under an assumed influence of the national wind power generation on spot prices.
- Finally, an additional average price spread of 40 €/MWh was determined so that the project becomes cost effective, meaning an increase by 200% in average from the current spread of 20 €/MWh between base-load hours, and semi-base and on-peak periods.

The power market tested has particularities that could benefit wind power through large price spreads, namely a high share of nuclear power setting a low base-load price, and a coal-based generation during peak times, which increase the on-peak prices. Moreover, fossil-fuel based imports have an increasing effect on the price spread.

The main issues raised in this study include: the balancing needs that the French market may face in the future, the value of the power quality, and the social cost of the supply security and energy independency. Either to expose the wind power to market price fluctuations or to protect it through regulated schemes remains a complex issue in front of the deregulation perspective in European power markets. Since the wind power cannot react to market signals, creating balancing market signals to encourage the participation of intermittent generators is unlikely to be successful because of the intermittency of the output. The option to contract a storage facility can solve imbalances, while offering additional option for supplying ancillary services and power quality through a continuous peak-load power. The storage technology should be sized to fully benefit from the storage of excess wind power during low demand periods. This is particularly valuable in areas with high wind turbine concentration and low population density.

Uncertainties in the future balancing market in particular make it difficult to estimate the system value from power quality, based on current market conditions to fulfill security and independency criteria. However, along with the decentralization, different market rules and designs need to be defined with respect to the responsibility and the quality of the delivery. They should provide the correct market signals to encourage generators and system operators to innovate and to diversify the supply and transmission options. The technology combination between storage and wind power would meet these requirements. Future simulations could evaluate the effect of load shaving, imports reduction, and removal of back-up capacities at the system level, which are important factors on the economics of local projects.

Acknowledgements

We are very grateful to our colleague, David Shropshire, for his precious comments on the content and the structure of this paper. Ideas expressed and remaining omissions are the sole responsibility of the authors.

Appendix A.

Overview of selected storage and wind related model parameters.

Technology	Unit size (turbine/ compressor) (MW)		Storage (MWh)	Fixed O&M (€/kWa)	Start-up costs (€/MW)	Other var costs (€/MWh)	Depreciation time (years)	Specific Inv. costs (€/MW)	Cold start-up time (h)
CAES	1200	1440	12,000	23.0	15	0.12	30	625,000	0.4
Wind	2000			24.0			20	925,000	

References

[1] Eurelectric Union of the Electricity Industry. Ancillary services. In: Unbundling electricity products – an emerging market, 2003-150-0007, Brussels; 2004, www.eurelectric.org.

[2] European Commission. Commission of the European Communities: Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: Offshore Wind Energy: action needed to deliver on the Energy Policy Objectives for 2020 and beyond. COM 2008:768.

[3] Hiroux C, Saguan M. Large-scale wind power in European electricity markets: time for revisiting support schemes and market designs? Energy Policy 2010;38(7):3135–45.

[4] Gross R, Heptonstall P, Anderson D, Green T, Leach M, Skea J. The Costs and Impacts of Intermittency: an assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network. UK Energy Research Centre; 2006, http://www.ukerc.ac.uk/Downloads/PDF/06/0604Intermittency/0604IntermittencyReport.pdf.

[5] Holttinen H, Meibom P, Orths A, Lange B, O'Malley M, Tande JO. et al. Impacts of large amounts of wind power on design and operation of power systems; results of IEA collaboration, *Conference Paper* NREL/CP-500-43540; 2008.

[6] Gatzen C. The economics of power storage – theory and empirical analysis for central Europe. München: Oldenbourg Industrieverlag; 2007.

[7] Eyer J, Corey G. Energy storage for the electricity grid: benefits and market potential assessment guide – a study for the DOE energy storage systems program. Sandia National Laboratories; 2010 SAND2010-0815.

[8] Loisel R, Mercier A, Gatzen C, Elms N, Petric H. Valuation framework for large scale electricity storage in a case with wind curtailment. Energy Policy 2010;38(11):7323–37, doi:10.1016/j.enpol.2010.08.007.

[9] Schoenung SM, Eyer J. Benefit/Cost framework for evaluating modular energy storage, Sandia report SAND2008-0978; 2008.

[10] EPRI. EPRI-DOE handbook of energy storage for transmission and distribution applications. Washington, DC: EPRI, Palo Alto, CA and the US Department of Energy; 2003.

[11] RTE. Schema de developpement du réseau public de transport d'électricité 2006–2020; 2009, http://www.rte-france.com/uploads/media/pdf_zip/nos-activit-s/RTE_schema_dev_2009_complet.pdf.

[12] Rebours Y. A comprehensive assessment of markets for frequency and voltage control ancillary services, PhD thesis, University of Manchester; 2008.

[13] DENA, Deutsche Energie Agentur. Integration into the national grid of onshore and offshore wind energy generated in Germany by the year 2020; 2005. Grid Study I.

[14] Gosset J, Ranchin T. Bilan et prospective de la filière éolienne française. Centre Energetique et Procedes, ARMINES/ADEME no. 50722; 2006.

[15] Ostergaard PA. Ancillary services and the integration of substantial quantities of wind power. Applied Energy 2006;83:451–63.

[16] NRAP, National Renewable Energy Action Plans. Plan d'action national en faveur des énergies renouvelables. Période 2009–2020; 2009. Available at http://ec.europa.eu/energy/renewables/transparency_platform/doc/national_renewable_energy_action_plan_france_fr.pdf.

[17] CRE, Commission de Regulation de l'Energie. La régulation du marche de l'électricité; 2006, http://lesrapports.ladocumentationfrancaise.fr/BRP/064000538/0001.pdf.

[18] ME. Ministère de l'Ecologie, du Développement Durable, des Transports et du Logement. In: Appel d'offres pour la création des centrales photovoltaïques en France; 2009, http://www.developpement-durable.gouv.fr/spip.php?page=article&id_article=11967.

[19] Gillhaus A. Natural gas storage in salt caverns – present status, developments and future trends in Europe; 2007, http://www.innovativeenergy.com.au/saltcavern/Europe%20salt%20caverns.pdf.

[20] European Commission. Technology Map of the European Strategic Energy Technology Plan (SET-Plan) Part – I: Technology Descriptions, JRC-SETIS Work Group, EUR 24117 EN – 2009; 2009.

[21] Ekman CK, Jensen SH. Prospects for large scale electricity storage in Denmark. Energy Conversion and Management 2010;51(6):1140–7.

[22] FNA – Federal Network Agency. Monitoringbericht. Report in German available at http://www.bundesnetzagentur.de/cae/servlet/contentblob/134810/publicationFile/1107/Monitoringbericht2009EnergieId17368pdf.pdf; 2009.

[23] Saenz de Miera G, del Rıo Gonzalez P, Vizcaıno I. Analysing the impact of renewable electricity support schemes on power prices: the case of wind electricity in Spain. Energy Policy 2008;36:3345–59.

[24] Lund H, Salgi G, Elmegaard B, Andersen AN. Optimal operation strategies of compressed air energy storage (CAES) on electricity spot markets with fluctuating prices". Applied Thermal Engineering 2009;29:799–806.

[25] Gicquel, A. Ancillary services. Obligation? Market? What about France? CRE, ERRA Licensing/Competition Committee Meeting, Kiev; 2008.

[26] EWEA. Wind energy and electricity prices. Exploring the merit order effect, Poyry; 2010, http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/MeritOrder.pdf.

[27] Bach PF. The effects of wind power on spot prices. London: Renewable Energy Foundation; 2009.

[28] Fabbri A, G'omez San Rom'an T, Rivier J, M'endez Quezada MH. Assessment of the cost associated with wind generation prediction errors in a liberalized electricity market. IEEE Transactions on Power Systems 2005;20(August (3)).

[29] Kaldellis JK, Kapsali M, Kavadias KA. Energy balance analysis of wind-based pumped hydro storage systems in remote island electrical networks. Applied Energy 2010;87:2427–37.

[30] European Commission. Structure and performance of Six European wholesale electricity markets in 2003, 2004 and 2005. DG COMP; 2007, http://ec.europa.eu/competition/sectors/energy/inquiry/electricity_final_part4.pdf.

[31] BCG, Boston Consulting Group. Donner un nouveau souffle a l'éolien terrestre; 2004, http://www.ventdecolere.org/archives/doc-references/BCG.pdf.

[32] Vandezande L, Meeus L, Belmans R, Saguan M, Glachant JM, Rious V. Lacking balancing market harmonisation in Europe: room for trader profits at the expense of economic efficiency? Post-Print, HAL; 2009, http://econpapers.repec.org/RePEc:hal:journl:hal-00422185_v1.

[33] Greenblatt JB, Succar S, Denkenberger DC, Williams RH, Socolow RH. Baseload wind energy: modeling the competition between gas turbines and compressed air energy storage for supplemental generation. Energy Policy 2007;35:1474–92.